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Infill Drilling Using Horizontal Wells: A Field Development Strategy for Tight Fractured Formations

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ABSTRACT

Gas production for a 10-year period was simulated for 16 vertical shot wells located in a 2,066-acre $(8.36 \times 10^6 m^2)$ area containing seven active vertical wells. The performance of several horizontal wells was simulated and the results were compared with that of the 16 vertical wells. Finally, the horizontal and vertical wells were compared to determine the best method for developing a virgin reservoir. As few as four unstimulated 2,000 ft (610 m) horizontal wells were found to produce 1.5 times as much gas as 16 vertical shot wells, and only two hydraulically fractured horizontal wells were needed to almost match the production of the four unstimulated horizontal wells. In a virgin reservoir, four unstimulated horizontal wells accounted for 95 percent of the total production from 23 vertical wells.

INTRODUCTION

The U.S. Department of Energy (DOE) has been con-ducting research to determine economical ways of producing natural gas from the Devonian shales for over 10 years. In support of this research, the United States Geological Survey (USGS) has esti-mated the in-place gas of the Appalachian Basin Devonian shales to be 577 to 1,100 Tcf[1] (1.6 x 10^13 to 3.1 x 10^13 m^3) with 85 to 160 Tcf (2.4 x 10^12 to 4.5 x 10^12 m^3) located in areas of historical shale gas production. As of 1976, only about 3 Tcf (8.5 x 10^10 m^3) of this large resource had been produced by about 10,000 vertical wells.[2] Gas pro-duction from the shales has not increased substan-tially since this time although the number of shale wells is now in excess of 16,000.

Earlier efforts by DOE[3] showed that it is not uncommon for only 10 to 20 percent of the available shale gas to be produced with stimulated vertical

wells and standard well spacing. Analysis of shale gas production mechanisms indicated that an increase in the amount of surface area connected to the borehole by fractures could cause more of the adsorbed gas to be released and produced over the entire life of the well. This potential increase in recovery efficiency was thought to be achievable using a directionally drilled horizontal well to cross natural fractures. Afterwards, the horizontal well would be stimulated to increase the surface area in contact with the borehole.

Infill drilling using horizontal wells is a rela-tively new concept as a field development strategy. A comprehensive reservoir simulation study has been conducted to compare horizontal shale wells with vertical shale wells for infill drilling and virgin reservoir development in Wayne County, West Vir-ginia, an area where vertical well gas production has been historically high and no permeability anisotropy is thought to exist. This study com-pares shot vertical wells with both stimulated and unstimulated 2,000 ft (610 m) horizontal shale wells for infill drilling and virgin reservoir development.

In this study, a three-dimensional, dual-porosity reservoir simulator was used to characterize the study area after sensitivity analyses were made to determine those parameters significant in determin-ing gas production profiles. Techniques for simu-lating gas production from a horizontal wellbore were developed by using a reservoir model to select a horizontal well site in Wayne County, West Vir-ginia, and then by fine tuning the model using well test data, production rates, and cores taken from the actual horizontal well.

BACKGROUND

Since the primary analysis tool used was a three-dimensional, dual-porosity reservoir simulator, it is important to understand how the model works and what is involved in history matching. The

References and illustrations at end of paper.

dual-porosity model simulates gas production per-formance from a naturally fractured reservoir. It depicts a dual-porosity system (Figure 1) in which gas is stored in the shale matrix (less permeable portion of the shale) and is subsequently released into the natural fracture network, which provides a transport mechanism for the gas when linked to the borehole. History matching consists of adjusting input parameters for a model until the simulated well or field performance is close to the actual historical performance.

Prior to drilling a 2,000 ft (610 m) horizontal well in Wayne County, West Virginia (Figure 2), a full-field simulation of the seven vertical shot wells near the well site was performed using this three-dimensional, dual-porosity gas simulator. Historical data from 25 of 38 wells (Figure 3) were used for this simulation, with the first well put into production in 1932. Individual well history matches were determined for each of the 25 wells by varying k_f and h and matching against production only. All other parameters were held constant and were taken from a previous DOE study.[4] These values are shown in Table 1.

Table 2 lists the important model-derived parameters determined by the individual well matches. A small area of approximately 2 mi^2 (5.18 km^2) that contained seven active shale wells was selected to simulate the performance of three 2,000 ft (610 m) horizontal wells (Figure 4), as well as three vertical shot wells located along the horizontal well sites. Data on the seven vertical wells is shown in Table 3, and results from this effort are shown in Table 4. Production labeled as interference in Table 4 is the amount of gas stolen from the seven active vertical shale wells by the corresponding horizontal well. The initial flow rate predicted by the model was 120 Mcfd (3.4 x 10^3 m^3/d) for the actual 2,000 ft (610 m) horizontal well (WHW2 in Figure 4), while the measured flow rate was 37 Mcfd (1.05 x 10^3 m^3/d). It was decided to perform the simulation again, making use of all the new data that were available after the horizontal well was drilled and tested. The purpose was to better explain the initial production performance of the horizontal well and to more accurately compare ver-tical shot wells with horizontal wells when used for infill drilling or virgin reservoir develop-ment. The data included a matrix permeability measurement taken from a core sample, flow rates and pressures taken from well testing, and natural fracture spacing taken from a downhole video camera. The original simulation matched production only when some of the key unknown parameters such as adsorbed gas, producing thickness, and vertical permeability were fixed at 83 percent of the gas-in-place, 180 ft (54.86 m), and $k_z = k_y = k_x$, respectively. Details of this simulation are described in a previous SPE paper.[5]

TECHNICAL APPROACH

This new simulation used a 9,000 ft x 10,000 ft or 3.25 mi^2 (2,743 m x 3,048 m or 8.4 km^2) area con-taining the same seven active vertical shale wells as the original study (Figure 5). Full-field his-tory matching was performed so that matches were obtained against (1) cumulative production for all seven wells, (2) 7-day shut-in pressures for three of the seven wells (taken in late 1985), and (3) pressure and initial flow rate for the 2,000 ft

(610 m) horizontal well. The full-field match also matched the individual well production histories (Table 5). A grid of 63 x 60 x 3 = 11,340 blocks was used with the vertical shot wells represented by 3 ft x 3 ft = 9 ft^2 (0.91 m x 0.91 m = 0.84 m^2) blocks and the horizontal well represented by 1 ft x 1 ft = 1 ft^2 (0.3 m x 0.3 m = 0.09 m^2) blocks. The vertical wells penetrated the entire producing thickness while the horizontal wells extended 2,000 ft (610 m) through the reservoir. The full-field simulation was conducted in order to characterize the study area for those parameters most affecting gas production, namely k_f, adsorbed gas, h, current rock pressure, and k_z. (See Figures 6 and 7.)

The initial reservoir pressure was 540 psi (3.7 MPa) and the current average rock pressure approximately 200 psi (1.38 MPa). A calculation was made to determine approximate values for productive thick-ness and adsorbed gas content. The equations used the ideal gas law and were functions of gas-in-place, system pressure change, and cumulative pro-duction. Based on the calculations, a producing thickness of 51 ft (15.54 m) and an adsorbed gas content of 0.0007 scf/ft^3/psia (0.0048 m^3/m^3/KPa) were determined. These values were substantially different from the original ones used of 180 ft (54.86 m) for the producing thickness and 0.005 scf/ft^3/psia (0.0345 m^3/m^3/KPa) for the adsorbed gas content. The percent of adsorbed gas-in-place was reduced from 83 to 32 for the new study. The 51 ft (15.54 m) producing thickness also agrees very well with a measured value for the Lower Huron (the producing shale zone) determined at a DOE-sponsored field test in Meigs County, Ohio.[6] Directional permeabilities for the fracture system were then varied until history matches were obtained for (1) current rock pressures for three of the seven wells and production profiles for all seven vertical wells, and (2) the initial flow rate and measured pressure for the 2,000 ft (610 m) horizontal well. Directional permeability varied laterally from 0.077 md to 2.47 md and was fixed at 0.01 md in the vertical direction. At this point, the study area was completely characterized; a well of any type could be placed anywhere in the area and its performance could be accurately pre-dicted. The simulation showed approximately 6,000,000 Mcf (1.7 x 10^8 m^3) of original-gas-in-place with the seven vertical wells producing approximately 51 percent of this gas as of late 1985. Reservoir data for this simulation is listed in Table 6.

VERTICAL VERSUS HORIZONTAL WELLS FOR INFILL DRILLING

After using history matching to characterize the 3.25 mi^2 (8.4 km^2) study area, several simulations were executed. These consisted of (1) placing 16 vertical wells in the study area, IV8-IV23 in Figure 8, and simulating their production from late 1985 until 1995; (2) simulating the production of four unstimulated 2,000 ft (610 m) horizontal wells simultaneously over the same 10-year time period, HW1-HW4 in Figure 9; and (3) simulating the pro-duction from two 2,000 ft (610 m) stimulated hori-zontal wells simultaneously for the same time period, SHW1-SHW2 in Figure 10. In each of these simulations, the seven active vertical shale wells, VW1-VW7 in Figure 9, were produced with the first well having come on-line in 1932.

Placing 16 vertical infill wells in the 3.25 mi^2 (8.4 km^2) study area reduced the well spacing from 295 to 90 acres (1.2 x 10^6 to 3.64 x 10^5 m^2). This spacing is not unusual for Devonian shale wells. Four unstimulated 2,000 ft (610 m) horizontal wells when used for infill drilling were shown to produce 1.5 times as much gas as 16 vertical shot wells. The four unstimulated horizontal wells showed a total gas production of 604 MMcf (1.7 x 10^7 m^3) and the 16 vertical wells had a combined production of 382 MMcf (1.08 x 10^7 m^3). Individual horizontal well production also varied widely with HW2 showing 215 MMcf (6.08 x 10^6 m^3) and HW1 showing 114 MMcf (3.2 x 10^6 m^3). Two stimulated 2,000 ft (610 m) horizontal wells were shown to produce almost as much gas as the four unstimulated horizontal wells, and stimulating a horizontal well with four 250 ft (76.2 m) winglength hydraulic fracture treatments was shown to substantially increase its production over a 10-year period (approximately 55 percent).

The stimulated horizontal wells were simulated by using 10 ft x 10 ft = 100 ft^2 (3.05 m x 3.05 m = 9.3 m^2) block that extended 2,000 ft (610 m) through the reservoir. Previous work showed this method to be equivalent to studying four 250 ft (76.2 m) winglength hydraulic fracture treatments in the reservoir. Production profiles for these simulations is summarized in Table 7.

The actual cost of completing the unstimulated 2,000 ft (610 m) horizontal well in Wayne County was four times that of a vertical well, while the predicted improvement in production of a horizontal well over a vertical one was six to one. Air was used as the drilling medium for completing this well. A significant reduction in drilling costs seems possible since a long horizontal well was recently completed in North Dakota[7] that only cost twice as much as a vertical completion.

VERTICAL VERSUS HORIZONTAL WELLS FOR VIRGIN RESERVOIR DEVELOPMENT

Several additional simulations were executed in order to compare vertical wells with horizontal wells when developing virgin reservoirs. These simulations "started" in 1932 and were run for a 10-year period. Since the reservoir had been characterized through history matching, this technique was equivalent to simulating the development of the reservoir when it was a virgin reservoir. The simulations investigated were (1) simulating 10-year production for 23 vertical shot wells, VW1-VW7 and IV8-IV23 in Figure 8, with all wells operating simultaneously; (2) simulating the 10-year production of four 2,000 ft (610 m) unstimulated horizontal wells simultaneously, HW1-HW4 in Figure 9; and (3) simulating the 10-year production of two 2,000 ft (610 m) stimulated horizontal wells simultaneously, SHW1-SHW2 in Figure 10.

Results from these simulations showed horizontal wells to be superior to vertical wells when used for developing virgin reservoirs. Four unstimulated horizontal wells accounted for 95 percent of the total production from 23 vertical shot wells, while two stimulated horizontal wells were again almost equivalent to four unstimulated ones.

Production figures for these simulations showed 2,649 MMcf (7.5 x 10^7 m^3) for the 23 vertical wells, 2,517 MMcf (7.1 x 10^7 m^3) for the four unstimulated horizontal wells, and 2,433 MMcf (6.9 x 10^7 m^3) for the two stimulated horizontal wells. Again, location was an important factor since HW2 produced 1,224 MMcf (3.5 x 10^7 m^3) of gas, while HW1 produced 368 MMcf (1.04 x 10^7 m^3) of gas. When developing a virgin reservoir, a stimulated horizontal well showed a 10-year increase in production of 34 to 47 percent over its unstimulated counterpart. Production data from these simulations are summarized in Table 8.

CONCLUSIONS

The following conclusions are supported by the analysis presented in this paper:

- Four horizontal wells can produce 1.5 times as much gas as 16 vertical wells when used for infill drilling or for virgin reservoir development.

- Only two horizontal wells were required to achieve the same effect whenever stimulation was added.

- In developing new areas, the production potential from four unstimulated horizontal wells is equal to that of 23 vertical wells. This can be reduced to two horizontal wells by applying stimulation to them.

- Reservoir simulation is a powerful aid in characterizing gas reservoirs and determining well locations for field development.

NOMENCLATURE

h = Net producing thickness, (ft).

k_f = Natural fracture permeability, (md).

k_x = Natural fracture permeability in the x-direction, (md).

k_y = Natural fracture permeability in the y-direction, (md).

k_z = Natural fracture permeability in the vertical direction, (md).

ACKNOWLEDGEMENT

REFERENCES

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3. Horton, A. I., J. C. Mercer, and W. K. Sawyer, "Infill Drilling for Shale Gas Development: A Field Case Study," SPE 11182, Presented at the 57th Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1982.

4. Lewin and Associates, Inc., "Technically Recoverable Devonian Shale Gas in West Virginia," Report to DOE, December 1984, DOE/MC/19239-1750, NTIS/DE85003367.

5. Salamy, S. P., B. S. Saradji, C. O. Okoye, J. C. Mercer, and A. B. Yost II, "Recovery Efficiency Aspects of Horizontal Well Drilling in Devonian Shale," SPE 16411, Presented at the SPE/DOE Low Permeability Reservoirs Symposium, Denver, Colorado, May 1987.

6. Frohne, K-H., and J. C. Mercer, "Fractured Shale Gas Reservoir Performance Study -- An Offset Well Interference Test," SPE 11224, Presented at the 57th Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1982.

7. "Meridian Sets Records for Horizontal Drilling," Oil and Gas Journal (March 7, 1988) 24.

TABLE 2

Parameters Determined by History
Matching, Wayne County, West Virginia,
Original Simulation

Parameter	Range
Current Rock Pressure	150-300 psia
Natural Fracture Permeability, k_f	.02-.16 md
Net Producing Thickness, h	40-310 ft
Flow Capacity, $k_f \cdot h$	1-42 md-ft

TABLE 3

Wayne County Original Study Area Data

Well	Completion Date	Cumulative Production* (MMcf)
VW1	1932	310
VW2	1941	382
VW3	1942	804
VW4	1955	1,370
VW5	1960	189
VW6	1965	24
VW7	1984	13

Field-Predicted Cumulative Production by Simulation = 3,098 MMcf.

Actual Field Cumulative Production = 3,092 MMcf.

* Values reported up to the end of 1985.

TABLE 1

Single Well Analysis Parameters Held
Constant, Wayne County, West Virginia,
Original Simulation

Parameter	Value
Gas Desorption Rate	0.005 scf/ft^3/psia
Drainage Radius	1,000 ft
Natural Fracture Spacing	5 ft
Matrix Porosity	0.01 (1%)
Matrix Permeability	5×10^{-6} md
Fracture Porosity	0.0009 (0.09%)
Permeability Anisotropy Ratio	1:1
Average Initial Rock Pressure	375 psia

TABLE 4

20-Year Cumulative Production for Wayne County (MMcf) Original Study

Well	Horizontal Shale Well Unstimulated	Stimulated	Interference	Vertical Shale Well Unstimulated	Stimulated	Interference	Improvement Ratio H:V
WHW1	820	1,659	187	78	--	78	10:1
WHW2	502	835	15	75	--	3	7:1
WHW3	149	589	70	22	--	20	7:1

TABLE 5

History Matching Data for New Simulation

Well Number	Cumulative Production (MMcf) Real	Cumulative Production (MMcf) Simulated	7-Day Shut-In Pressure (psi) Real	7-Day Shut-In Pressure (psi) Simulated
VW1	310	309	--	--
VW2	382	377	--	213
VW3	804	787	196	215
VW4	1,370	1,314	200	181
VW5	189	188	260	262
VW6	24	24	--	186
VW7	13	13	--	176
Total	3,092	3,012		

TABLE 6

Reservoir Data for New Simulation

Parameter	Value
Gas Desorption Rate	0.0007 scf/ft^3/psia
Natural Fracture Spacing	5 ft
Matrix Porosity	0.02 (2%)
Matrix Permeability	0.00082 md
Fracture Porosity	0.0009 (0.09%)
Permeability Anisotropy Ratio	1:1
Initial Rock Pressure	540 psia
Initial Gas-In-Place	6,000,000 Mcf
Net Producing Thickness	51 ft
Average Natural Fracture Permeability	0.69 md
Range of Natural Fracture Permeabilities	0.077-2.47 md
Vertical Permeability	0.01 md
Percent of Free Gas in the Fractures	2.9%
Percent of Free Gas in the Matrix	65.4%
Percent of Adsorbed Gas	31.7%
Average Current Rock Pressure	200 psia

TABLE 7

10-Year Cumulative Production for Infill Wells (MMcf)

Well Number	Type	Production
IV8	Infill Vertical	28
IV9	Infill Vertical	20
IV10	Infill Vertical	13
IV11	Infill Vertical	40
IV12	Infill Vertical	26
IV13	Infill Vertical	31
IV14	Infill Vertical	29
IV15	Infill Vertical	17
IV16	Infill Vertical	18
IV17	Infill Vertical	15
IV18	Infill Vertical	23
IV19	Infill Vertical	30
IV20	Infill Vertical	26
IV21	Infill Vertical	22
IV22	Infill Vertical	21
IV23	Infill Vertical	23
Total		382
HW1	Infill Horizontal	114
HW2	Infill Horizontal	215
HW3	Infill Horizontal	154
HW4	Infill Horizontal	121
Total		604
SHW1	Stimulated Infill Horizontal	330
SHW2	Stimulated Infill Horizontal	239
Total		569

TABLE 8

10-Year Cumulative Production for Wells Starting Production in 1932 (MMcf)

| Well Number	Type	Production
VW1	Vertical	48
VW2	Vertical	79
VW3	Vertical	179
VW4	Vertical	587
VW5	Vertical	95
VW6	Vertical	24
VW7	Vertical	362
IV8	Vertical	88
IV9	Vertical	71
IV10	Vertical	59
IV11	Vertical	159
IV12	Vertical	83
IV13	Vertical	91
IV14	Vertical	84
IV15	Vertical	51
IV16	Vertical	73
IV17	Vertical	65
IV18	Vertical	69
IV19	Vertical	85
IV20	Vertical	75
IV21	Vertical	70
IV22	Vertical	71
IV23	Vertical	81
Total		2,649
HW1	Unstimulated Horizontal	368
HW2	Unstimulated Horizontal	1,224
HW3	Unstimulated Horizontal	543
HW4	Unstimulated Horizontal	382
Total		2,517
SHW1	Stimulated Horizontal	1,635
SHW2	Stimulated Horizontal	798
Total		2,433
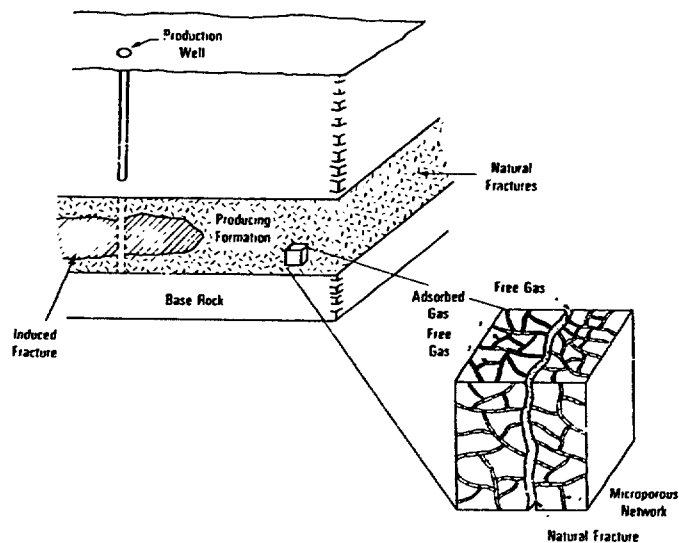
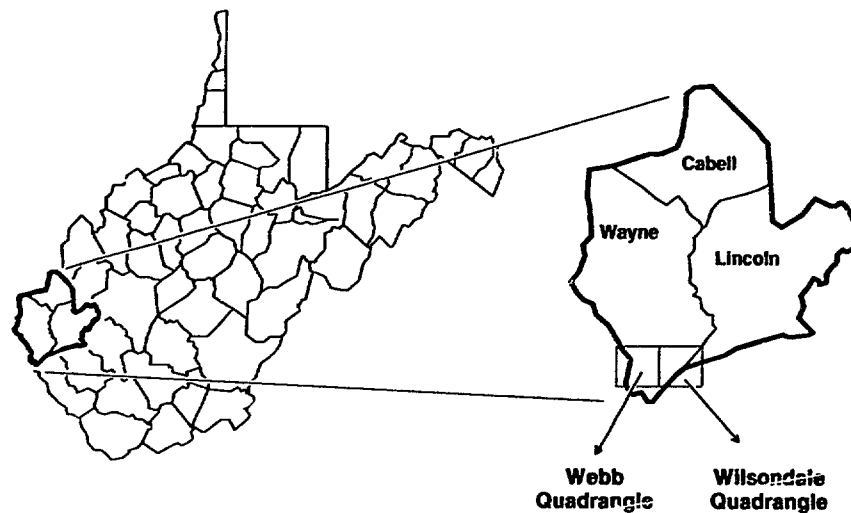Fig. 1—Model depiction of shale gas storage and production.
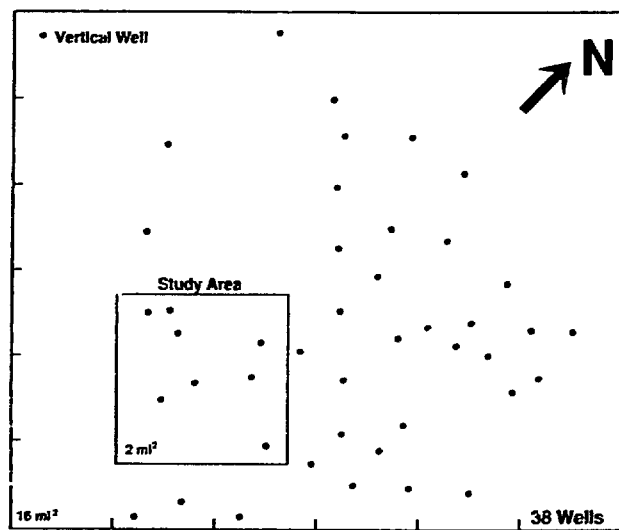

Fig. 2—Wayne County study area.
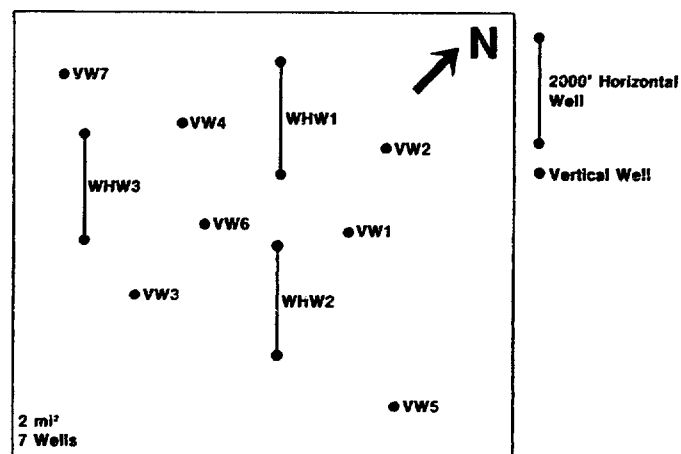

Fig. 3—Well location map for Wayne County study area.
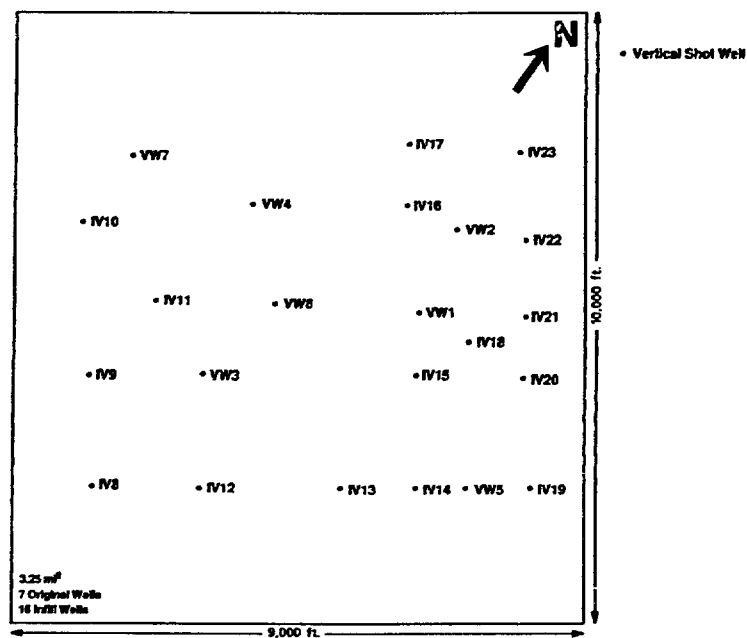

Fig. 4—Wayne County reduced-site well location map.

Fig. 5—History-matching study area and well locations.

Fig. 6—Natural fracture permeability distribution for study area (contours in millidarcies).

Fig. 7—Current rock pressure distribution (contours in pounds per square inch).

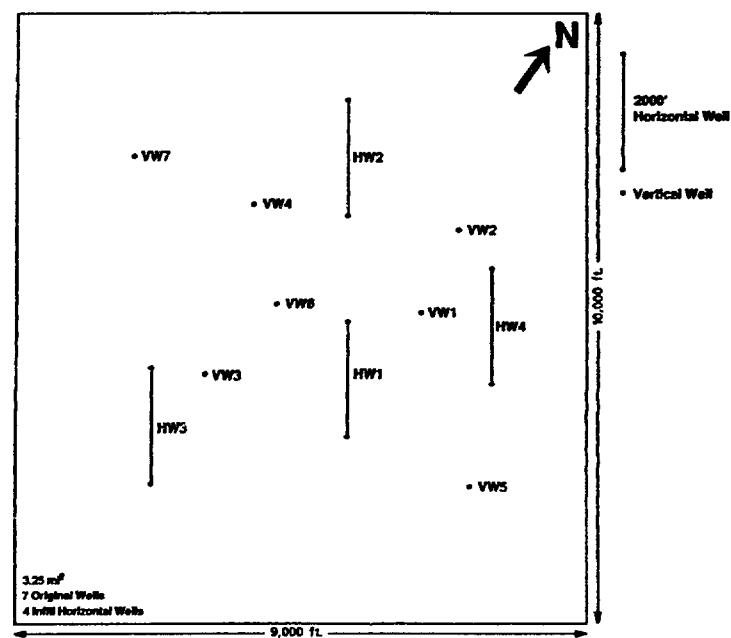Fig. 8—Well location map for vertical infill wells.

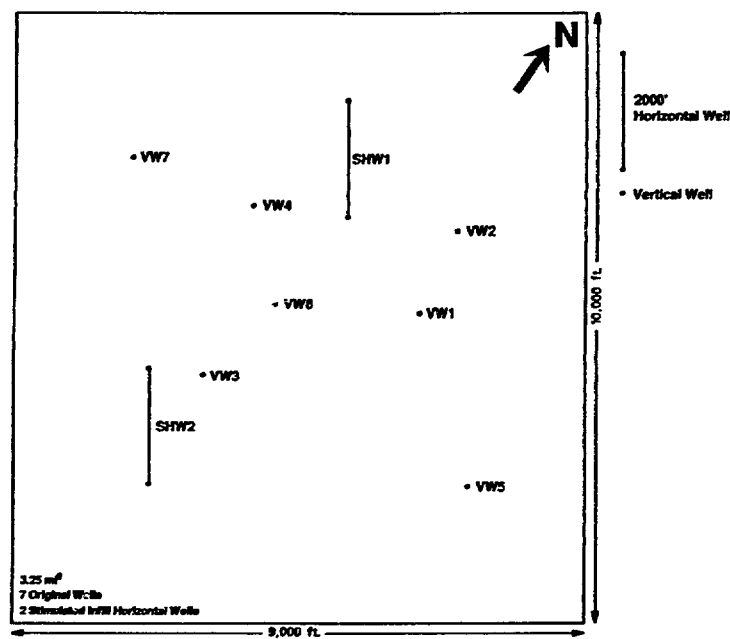Fig. 9—Well location map for unstimulated horizontal infill wells.

Fig. 10—Well location map for stimulated horizontal infill wells.